AIR QUALITY PERMIT

Issued to:	Exxon Mobil Corporation ExxonMobil Refining & Supply Co. Billings Refinery P.O. Box 1163 Billings, MT 59103-1163	Permit #1564-16 Application Complete: 02/09/05 Preliminary Determination Issued: 02/18/05 Department Decision Issued: 03/08/05 Permit Final: 03/24/05 AFS #111-0013

An air quality permit, with conditions, is hereby granted to Exxon Mobil Corporation (ExxonMobil) pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.740, *et seq.*, as amended, for the following:

Section I: Permitted Facilities

A. Location

The ExxonMobil – Billings Refinery is located at 700 Exxon Road in Billings, Montana. The Yellowstone River forms the northern and northeastern boundaries, and Interstate 90 lies along the southern border. Refinery units and storage tanks lie in the southern half of Section 24 and the northern half of Section 25, Township 1 North, Range 25 East, in Yellowstone County, Montana. The active refinery occupies approximately 380 acres on a level plot.

B. Permitted Facility

This permit covers all existing sources of air contaminants at the above-described petroleum facility. A list of permitted equipment can be found in the permit analysis section of this permit. The refinery also includes the bulk marketing distribution terminal, which stores and transfers petroleum products (gasoline and distillate) received from the refinery and distributes them to regional markets via tank truck. The terminal is located adjacent to and south of the refinery and operates under air quality Permit #2967-00.

C. Current Permit Action

On February 9, 2005, the Department of Environmental Quality (Department) received a complete Montana Air Quality Permit Application from ExxonMobil to modify Permit #1564-15. The purpose of the application is to address the replacement of six existing convection section tubes with six new finned convection section tubes in the Steam Reforming Furnace (F-551) located in the Hydrogen Plant. Replacing and finning the upper tube row in the secondary preheat coil of F-551 allows for improved heat absorption from the process stream which in turn results in improved Hydrogen Plant production. The current modifications will directly affect F-551 and, potentially, indirectly increase throughput to the fluidized catalytic cracking unit (FCCU), Alkylation Unit, Powerformer Unit, and Hydrocracker Unit. Crude oil throughput will not increase as a result of this modification. This permitting action results in lowering the existing limit on refinery-wide fuel oil combustion so that the overall sulfur dioxide (SO_2) and particulate matter (PM) emissions increase from the project will be below the Prevention of Significant Deterioration (PSD) SO_2 and PM significance levels. Section II.F.2 of the permit analysis includes a discussion of the netting analysis conducted for the current permit action.

Section II. Limitations and Conditions

A. General Facility Conditions

1. ExxonMobil shall, any time the Yellowstone Energy Limited Partnership (YELP) facility is operating, send all of its coker process gas to either one or both of YELP's boilers. During startup and shutdown conditions at YELP, ExxonMobil shall supply the maximum amount of coker process gas that YELP can accept.

2. A refinery-wide block hourly limit of 0.96 lb of sulfur in fuel per MMBtu fired shall be adhered to at all times. Compliance with this sulfur-in-fuel limit shall be determined according to the techniques outlined in ExxonMobil's letter dated September 25, 1989, (Appendix A), as adjusted to measure the sulfur-in-fuel limit on an hourly basis. For determining the sulfur weight percent, ExxonMobil may also use American Society for Testing and Materials (ASTM) Method D2622 or another method as may be approved by the Department. In the event ExxonMobil fails to meet the hourly limit of 0.96 lb of sulfur per MMBtu fired, ExxonMobil shall immediately notify YELP of this occurrence. After such an occurrence, ExxonMobil shall also provide subsequent notification to YELP when it has met the hourly sulfur-in-fuel limitation for 3-consecutive hourly periods.

3. Refinery-wide fuel oil consumption by the fluidized catalytic cracker carbon monoxide (FCC CO) Boiler shall not exceed 720 barrels per calendar day. Verification that this value has not been exceeded shall be determined by the technique outlined in Appendix A. In the event ExxonMobil exceeds the daily limit on fuel oil firing, ExxonMobil shall immediately notify YELP of the occurrence. After such an occurrence, ExxonMobil shall also provide subsequent notification to YELP when it is back in compliance with the above limitation.

4. Any time ExxonMobil diverts process coker gases from YELP, ExxonMobil shall report said diversion to the Department within 24 hours or during the next working day. This information shall also be included in the quarterly continuous emission monitors (CEMS) sulfur-in-fuel report and include period(s) of diversion, quantity of sulfur oxide emissions, reason(s) for diversion(s), and corrective measures taken to prevent recurrence.

5. Refinery-wide fuel oil consumption by the FCC CO Boiler shall not exceed 36.5 kbarrels (1,000 barrels) during any rolling 12-month period following the completion of the modifications associated with Permitting Action #1564-13 (ARM 17.8.749).

6. Refinery-wide fuel oil consumption by the FCC CO Boiler shall not exceed 28.3 kbarrels during any rolling 12-month period following the completion of the modifications associated with Permitting Action #1564-16 (ARM 17.8.749).

7. Refinery-wide fuel oil consumption by the FCC CO Boiler shall not exceed 3.0 kbarrels during any rolling 12-month period following the completion of the modifications associated with Permitting Action #1564-15 (ARM 17.8.749).

8. ExxonMobil shall comply with all the applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR 60, Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry, as it applies to this refinery (ARM 17.8.340 and 40 CFR 60, Subpart VV).

9. ExxonMobil shall comply with all the applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR 60, Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, as it applies to this refinery (ARM 17.8.340 and 40 CFR 60, Subpart GGG).

10. ExxonMobil shall comply with all the applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR 60, Subpart J – Standards of Performance for Petroleum Refineries, as it applies to this refinery, unless exempted or unless otherwise specified as a condition of Permit #1564-12 (ARM 17.8.340 and 40 CFR 60, Subpart J).

11. ExxonMobil shall comply with all the applicable standards and limitations, and the monitoring, recordkeeping and notification requirements of 40 CFR 63, Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as it applies to this refinery. This requirement includes the vapor control equipment installed on Tank #309 (ARM 17.8.342 and 40 CFR 63, Subpart CC).

B. Polymer Modified Asphalt (PMA) Unit

1. ExxonMobil shall maintain the operating temperature of the wetting/mixing tank below the smoking point of asphalt. ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere, from the wetting/mixing tank, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 and 17.8.752).

2. All valves used shall be high quality valves containing high quality packing (ARM 17.8.752).

3. All open-ended valves shall be of the same quality as the valves described above, and they shall have plugs or caps installed on the open end (ARM 17.8.752).

4. All pumps and mills used in the PMA unit shall be equipped with standard high quality single seals (ARM 17.8.752).

5. Flanges shall be equipped with process-compatible gasket material.

6. All applicable requirements of ARM 17.8.340, which reference 40 CFR Part 60, Standards of Performance for New Stationary Sources and Subpart GGG – Equipment Leaks of VOC in Petroleum Refineries, shall apply to the PMA process unit and any other equipment, as appropriate. A monitoring and maintenance program, as described under New Source Performance Standards (40 CFR Part 60, Subpart VV), shall be instituted. Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years.

7. The Department may require testing (ARM 17.8.105).

8. The PMA unit may process either non-polymerized or polymer modified asphalt.

C. D-4 Drum Atmospheric Vent Stack

1. ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the D-4 drum atmospheric vent stack that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

2. The D-4 drum atmospheric vent stack shall have steam injection capability and shall be used whenever hydrogen sulfide (H_2S) is being released or is expected to be released from a process unit to the D-4 drum (ARM 17.8.749).

3. The Department may require testing (ARM 17.8.105).

D. FCC CO Boiler Stack

1. ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere, from the FCC CO Boiler stack, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes, except as allowed under the rule (ARM 17.8.304).

2. The Department may require testing (ARM 17.8.105).

E. F-2 Crude/Vacuum Heater Stack

1. ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the F-2 Crude/Vacuum Heater stack that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes, except as allowed under the rule (ARM 17.8.304).

2. The Department may require testing (ARM 17.8.105).

F. Furnace F-1201

1. Ultra Low nitrogen oxides (NO_X) Burners (ULNB) shall be used in furnace F-1201 to control NO_X emissions. The NO_X emissions shall not exceed 5.94 pounds per hour (lb/hr) and 0.060 pounds per million British thermal units (lb/MMBtu) (ARM 17.8.752).

2. The CO emissions from furnace F-1201 shall not exceed 7.77 lb/hr and 0.0785 lb/MMBtu (ARM 17.8.749).

3. ExxonMobil shall not cause or authorize to be discharged into the atmosphere from furnace F-1201, any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

4. Furnace F-1201 shall not consume more than 811 million standard cubic feet (MMscf) of Refinery Fuel Gas (RFG) and natural gas combined during any rolling 12-month period (ARM 17.8.749).

G. Furnace F-700 (after modifying to increase the capacity above 105.6 MMBtu/hr)

1. ULNB shall be used in the modified furnace F-700 to control NO_X emissions. The NO_X emissions shall not exceed 9.73 lb/hr (ARM 17.8.752).

2. The CO emissions from the modified furnace F-700 shall not exceed 9.58 lb/hr (ARM 17.8.749).

3. ExxonMobil shall not cause or authorize to be discharged into the atmosphere, from the modified F-700 furnace, any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

4. The modified furnace F-700 shall not consume more than 995 MMscf of RFG and natural gas combined during any rolling 12-month period (ARM 17.8.749).

H. Process Heater F-201 and Process Heater F-5

1. The NO_X emissions from F-201 shall not exceed 4.70 lb/hr (ARM 17.8.752).

2. The NO_X emissions from F-5 shall not exceed 6.27 lb/hr (ARM 17.8.752).

3. The combined NO_X emissions from F-5 and F-201 shall not exceed 33.30 tons per rolling 12-month period (ARM 17.8.752).

4. The refinery fuel gas burned in F-201 and F-5 shall not average more than the NSPS Subpart J limit of 160 ppm H_2S per rolling 12-month period (ARM 17.8.749).

I. Furnace F-551

1. The NO_X emissions from F-551 shall not exceed 23.35 lb/hr (ARM 17.8.749).

2. ExxonMobil shall not cause or authorize to be discharged into the atmosphere from F-551, any visible emissions that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

3. The NO_X emissions from F-551 shall not exceed 75.55 tons per rolling 12-month period (ARM 17.8.752).

J. RFG Combustion Sources

1. The following combined emission limitations shall apply to furnace F-1201 and all other "Affected Equipment and Facilities" identified in Exhibit A of the Stipulation of the Department and ExxonMobil whenever the YELP facility is receiving ExxonMobil coker flue gas or whenever ExxonMobil's coker unit is not operating (ARM 17.8.749).

   a. Combined 3-hour emissions of SO_2 from the RFG combustion units shall not exceed 92.4 lb per 3-hour period, and

   b. Combined daily emissions of SO_2 from the RFG combustion units shall not exceed 739.2 lb per calendar day.

2. The following combined emission limitations shall apply to furnace F-1201 and all other "Affected Equipment and Facilities" identified in Exhibit A of the Stipulation of the Department and ExxonMobil whenever the YELP facility is not receiving ExxonMobil's coker unit flue gas and ExxonMobil's coker unit is not operating (ARM 17.8.749).

   a. Combined 3-hour emissions of SO_2 from the RFG combustion units shall not exceed 76.2 lb per 3-hour period, and

   b. Combined daily emissions of SO_2 from the RFG combustion units shall not exceed 609.6 lb per calendar day.

3. The RFG used in each of the furnaces (F-1201 and the modified F-700) shall not exceed 160 ppm_v (230 milligrams per dry standard cubic meter (mg/dscm) or 0.10 grains per dry standard cubic foot (gr/dscf) of H_2S (ARM 17.8.340 and 40 CFR 60, Subpart J).

K. Tank 26

VOC fugitive emissions from Tank 26 shall not exceed 515 tons per rolling 12-month period. The fugitive emissions shall be determined using the following equation (ARM 17.8.749).

$W_{VOC} = 0.166677\ lb/ft^3 * V_{inst} * [TVP / (12.9-TVP)]$

Where:

W_{VOC} = Mass of hydrocarbon emissions in lb/day
V_{inst} = Air volume flowrate in standard cubic feet per day
TVP = True vapor pressure of hydrocarbons in lb/in^2 absolute

L. Operational Reporting Requirements

1. ExxonMobil shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the most recent emission inventory report and sources identified in the permit.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used for calculating operating fees, based on the actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. ExxonMobil shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

3. All records complied in accordance with this permit must be maintained by ExxonMobil as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

4. ExxonMobil shall document, by month, the total amount of RFG/natural gas consumed by furnace F-1201. By the 25th day of each month ExxonMobil shall calculate the total amount of RFG/natural gas consumed by furnace F-1201 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.F.4. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.L.1 (ARM 17.8.749).

5. ExxonMobil shall document, by month, the total amount of RFG/natural gas consumed by furnace F-700. By the 25th day of each month ExxonMobil shall calculate the total amount of RFG/natural gas consumed by furnace F-700 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.G.4. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.L.1 (ARM 17.8.749).

6. ExxonMobil shall document by month, the average monthly percent of maximum firing rate, the monthly gas consumption (MMscf per month), the input fuel heat content (MMBtu/MMscf), and the monthly hours of operation of F-201 and F-5 for use in the following equations:

   Y = m * (X/100) + b

   Where:

   Y=Emission factor at a specific firing rate (lb/MMBtu)
   m=Slope factor (lb/MMBtu) / (% firing rate)
   X=% of maximum firing rate
   b=y-intercept (lb/MMBtu)

For F-201	For F-5
m = -0.0329	m = -0.1253
b = 0.141	b = 0.261

   NO_X lb/hr = {(Y) * (gas consumption (MMscf/month)) * (fuel heat content (MMBtu/MMscf))} / (hours of operation per month (hr/month))

   NO_X tons per month = {NO_X (lb/hr) * (hr/month)} / 2000 lb/ton

7. ExxonMobil shall document, by month, the amount of total NO_X emissions from F-201 and F-5. By the 25th day of each month ExxonMobil shall calculate the total amount of NO_X emissions from F-201 and F-5 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.H.3. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.L.1 (ARM 17.8.749).

8. ExxonMobil shall document, by month, the average concentration of H_2S (ppm) in the refinery fuel gas burned in F-201 and F-5. By the 25th day of each month ExxonMobil shall average the concentration of H_2S (ppm) in the refinery fuel gas burned in F-201 and F-5 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.H.4. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.L.1 (ARM 17.8.749).

9. ExxonMobil shall document, by month, the total fugitive VOC emissions from Tank 26. By the 25th day of each month ExxonMobil shall total the fugitive VOC emissions from Tank 26 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.K. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.L.1 (ARM 17.8.749).

10. ExxonMobil shall document, by month, the facility-wide fuel oil combustion. By the 25th day of each month ExxonMobil shall calculate the total amount of facility-wide fuel oil combustion during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.A.5 and Section II.A.6. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.L.1 (ARM 17.8.749).

M. Testing Requirements

1. Within 180 days of initial startup, ExxonMobil shall test furnace F-1201 in order to demonstrate compliance with the NO_X and CO limitations specified in Sections II.F.1 and II.F.2 (ARM 17.8.106 and 17.8.749).

2. Within 180 days of the modification of furnace F-700, ExxonMobil shall test the modified furnace F-700 in order to demonstrate compliance with the NO_X and CO limitations specified in Sections II.G.1 and II.G.2 (ARM 17.8.106 and 17.8.749).

3. ExxonMobil shall test furnace F-1201 on an every 5-year basis after the initial source test, or according to another testing/monitoring schedule as may be approved by the Department, to demonstrate compliance with the NO_X limitations for furnace F-1201 found in Section II.F.1 (ARM 17.8.106 and 17.8.749).

4. ExxonMobil shall test the modified furnace F-700 on an every 5-year basis after the initial source test referenced in Section II.M.2, or according to another testing/monitoring schedule as may be approved by the Department, to demonstrate compliance with the NO_X limitation for the modified furnace F-700 found in Section II.G.1 (ARM 17.8.106 and 17.8.749).

5. Within 180 days of the modification of Hydrofiner #1, ExxonMobil shall test Process Heater F-201 in order to demonstrate compliance with the NO_X limitation specified in Section II.H.1 (ARM 17.8.106 and 17.8.749).

6. Within 180 days of the modification of Hydrofiner #3, ExxonMobil shall test Process Heater F-5 in order to demonstrate compliance with the NO_X limitation specified in Section II.H.2 (ARM 17.8.106 and 17.8.749).

7. Within 180 days of the modification of furnace F-551, ExxonMobil shall test furnace F-551 in order to demonstrate compliance with the NO_X limitation specified in Sections II.I.1 (ARM 17.8.106 and 17.8.749).

8. ExxonMobil shall test furnace F-551 on an every 5-year basis after the initial source test, or according to another testing/monitoring schedule as may be approved by the Department, to demonstrate compliance with the NO_X limitation for furnace F-551 found in Section II.I.1 (ARM 17.8.106 and 17.8.749).

9. Compliance and enforcement of the requirements on SO_2 emission rates and H_2S concentrations in Sections II.J.1, II.J.2, and II.J.3 shall be determined by utilizing data taken from continuous emission monitor systems (CEMS) and other Department-approved sampling methods. However, opacity compliance may also be determined via EPA Reference Method 9 by a certified observer.

a. The above does not relieve ExxonMobil from meeting any applicable requirements of 40 CFR 60, Appendices A and B, or other stack testing that may be required by the Department.

b. Other stack testing may include, but is not limited to, the following air pollutants: SO_2, NO_X, CO, particulate matter (PM, PM_{10}), and VOC.

c. Reporting requirements shall be consistent with 40 CFR 60, or as specified by the Department.

d. All gaseous continuous emission monitors shall be required to comply with quality assurance/quality control procedures in 40 CFR 60, Appendix F. H_2S CEMS shall be required to be maintained such that they are available and operating at least 90% of the source operating time during any reporting period (quarterly).

e. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, ExxonMobil shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated. The Department shall approve such contingency plans.

10. Compliance testing and continuous monitor certification shall be as specified in 40 CFR 60, Appendices A and B. Test methods and procedures, where there is more than one option for any given pollutant, shall be worked out with the Department prior to commencement of testing.

11. ExxonMobil shall conduct compliance testing and continuous monitor certification as specified in 40 CFR 60, Appendices A and B, within 180 days of initial startup of the affected facility.

12. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

13. The Department may require further testing (ARM 17.8.105).

N. Notification Requirements

ExxonMobil shall provide the Department with written notification of the following dates within the specified time periods (ARM 17.8.749):

1. Commencement of construction of furnace F-551, commencement of modification of furnace F-551 within 30 days of commencement of construction/change of the unit.

2. Actual startup date of furnace F-551, the modified furnace F-551 within 30 days after the actual startup date of the unit.

3. Commencement of construction of furnace F-1201, commencement of modification of furnace F-700, and the change in the method of operation of Tank 26 within 30 days of commencement of construction/change of each unit.

4. Actual startup date of furnace F-1201, the modified furnace F-700, and the change in the method of operation of Tank 26 within 30 days after the actual startup date of each unit.

5. Commencement of modification of Hydrofiner #1 and Hydrofiner #3 within 30 days of commencement of construction/change of each unit.

6. Actual startup date of the modified Hydrofiner #1 and Hydrofiner #3 within 30 days after the actual startup date of each unit.

7. Actual start-up date of offsite piping and production of ultra-low sulfur diesel that results in the 2,011 barrel/day increase in FCCU rate and a 2,139 barrel/day increase in mogas production, within 30 days of actual start-up.

8. Within 180 days of initial startup of the changes permitted in Permit #1564-09, ExxonMobil shall provide the Department with the final design parameters of the new or modified equipment, including, but not limited to, a material balance (stream level detail), process information, and the engineering data from the change in the method of operation of Tank 26 as agreed upon with the Department.

9. Actual start-up date of the Fluid Coker following modifications listed under Permit #1564-13 (specifically those modifications which allow the 500 barrels/day increase in fresh feed) within 30 days of actual start-up.

O. Monitoring and Reporting

1. ExxonMobil shall install, operate and maintain the applicable CEMS as required by 40 CFR 60, Subpart J. Emission monitoring shall be subject to 40 CFR 60, Subpart J, Appendix B (Performance Specification 7) and Appendix F (Quality Assurance/ Quality Control) provisions. Any stack testing that may be required (in Section II.M) shall be conducted according to 40 CFR 60, Appendix A and ARM 17.8.105, Testing Requirements provisions.

2. ExxonMobil shall provide quarterly emission reports from said emission rate monitors. Emission reporting for SO_2 from all point source locations shall consist of 24-hour calendar-day totals per quarter. The quarterly report shall also include the following:

   a. Source or unit operating times during the reporting period.

   b. Monitoring downtime that occurred during the reporting period.

   c. A summary of excess H_2S concentrations and/or SO_2 emissions and averaging period, for each new unit, as identified in Section II.I.

   d. Reasons for any emissions in excess of those specifically allowed in Section II.I, with mitigative measures utilized and corrective actions taken to prevent a recurrence of the upset situation.

   ExxonMobil shall submit quarterly emission reports within 30 days of the end of each calendar quarter.

3. ExxonMobil shall keep the Department apprised of the status of construction of the new and modified units, dates of performance tests, and continuous compliance status for each emission point and pollutant. Specifically, the following report and recordkeeping shall be required in writing:

   a. Notification of initial emission tests and monitor certification tests.

   b. Submittal for review by the Department of the emission testing plan, results of initial compliance tests, continuous emission monitor certification tests, continuous emission monitoring and continuous emission monitoring quality assurance/quality control plans, and excess emissions report format within the 180-day shakedown period.

   c. Copies of quarterly emission reports, H_2S and SO_2 monitoring data, excess emissions, and all other such items mentioned in Section II.N.3.a and b, above, shall be submitted to both the Billings regional office and the Helena office of the Department.

   d. Monitoring data shall be maintained for a minimum of 5 years at the Billings ExxonMobil Refinery.

   e. All data and records that are required to be maintained must be made available, upon request, to representatives of the Department and the U.S. Environmental Protection Agency.

Section III. General Conditions

A. Inspection – ExxonMobil shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if ExxonMobil fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving ExxonMobil of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement – Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties or other enforcement action as specified in Section 75-2-401, *et seq*., MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy the air quality permit shall be made available for inspection by the Department at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, failure to pay the annual operation fee by ExxonMobil may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. Construction Commencement – Construction must begin within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall be revoked (ARM 17.8.762).

Permit Analysis
Exxon Mobil Corporation – Billings Refinery
Permit #1564-16

I. Introduction/Process Description

A. Site Location

The Exxon Mobil Corporation – Billings Refinery (ExxonMobil) is located in the S½ of Section 24 and the N½ of Section 25, Township 1 North, Range 25 East, Yellowstone County, Montana. The bulk-marketing terminal is located adjacent to the refinery and operates under a separate preconstruction permit.

B. Existing Source Description

This permit provides external emission offsets from the ExxonMobil refinery for the issuance of a permit for an adjacent facility owned and operated by Yellowstone Energy Limited Partnership (YELP) (Permit #2650-01, dated February 14, 1992, and subsequent permits). These offsets are provided by the following requirements contained in this permit: required delivery of all coker process gas stream to YELP any time YELP is operating (Section II, Part A); an hourly limitation on sulfur-in-fuel burned at the refinery (Section II, Part B); and a daily limit on the number of barrels of fuel oil that may be burned at the refinery (Section II, Part C). In addition, to ensure these offsets are enforceable and to protect the integrity of the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (SO_2), ExxonMobil is required to provide notice to YELP in the event that it fails to comply with the requirements contained herein concerning either the hourly sulfur-in-fuel limitation (Section II, Part B) or the daily fuel oil firing limit (Section II, Part C). These requirements do not apply when YELP is not operating its facility, since emission offsets are not required (Permit #1564-03).

This permit includes, but is not limited to, the following equipment:

1. One coke producing coker facility with an associated carbon monoxide (CO) boiler capable of producing steam for use in the general facility.

2. One CO boiler (Coker CO Boiler).

3. All refinery fuel oil and fuel gas-consuming combustion units (i.e., boilers, furnaces, etc.).

4. An 800-ton/day Polymer Modified Asphalt (PMA) unit, which includes the following equipment (Permit #1564-04):

   a. Two 1948 5,000-barel (bbl) storage tanks with internal steam coil (Tanks 76 and 77)
   b. One 1966 circulation pump (P-58)
   c. One 1948 loadout (west rack)
   d. One fixed roof wetting/mixing tank (approximately 265 gallons)
   e. One high sheer mill feed pump (ratio pump)
   f. One high sheer mill (centrifugal pump)
   g. One sales dispensing pump (P-1A)
   h. Various valves and flanges

5. One D-4 drum atmospheric vent stack extension, from 40.8 to 70.1 meters, with added steam injection capability to raise the equivalent height of the stack to 79.2 meters (Permit #1564-05).

6. One Fluidized Catalytic Cracker (FCC)/CO Boiler stack extension.

7. Tank 26 (Change in the method of operation as part of Permit #1564-09)

8. Furnace F-1201 (Installed under Permit #1564-09).

9. Furnace F-700 (Modified to increase capacity in Permit #1564-09).

10. Hydrofiner #1 (Modified to produce and segregate ULSD Products in Permit #1564-14 and 15).

11. Hydrofiner #3 (Modified to produce and segregate ULSD Products in Permit #1564-14 and 15).

12. Furnace F-551 (Modified to increase capacity in Permit #1564-16).

C. Process Description

The ExxonMobil refinery converts crude oil into various refined products including refinery fuel gas (RFG), liquefied petroleum gas (LPG), aviation fuels, unleaded gasoline, jet fuels, kerosene, diesels, heavy fuel oil, asphalts, and fluid petroleum coke. The following is a brief summary of the petroleum refining process at the ExxonMobil facility.

Crude oil is generally a mixture of paraffinic, naphtheic, and aromatic hydrocarbons with some impurities including sulfur, nitrogen, oxygen, and metals. Refining at ExxonMobil begins by physically separating the crude oil constituents into common-boiling-point fractions using three separation processes: atmospheric distillation, vacuum distillation, and light ends recovery. Through various means, residual oils, fuel oils and light ends are converted to gasolines, jet fuels, and diesel fuels; heavier ends are converted to asphalt and coke.

Cracking and coking split large petroleum molecules into smaller ones. The alkylation processes use a catalyst to react small petroleum molecules together to make larger ones. The reforming process rearranges the structure of petroleum molecules to produce higher-octane value molecules of a similar molecule size. Using this conversion process, low-octane naphtha can be converted into high-octane gasoline.

Fuel gas streams containing H_2S are typically sent to Montana Sulphur and Chemical Company (MSCC), where they are treated in an amine treatment unit that separates the H_2S from the cleaned fuel gas. The clean fuel is returned to the refinery where it is used in the refinery process heaters and boilers.

D. Permit History

The Billings Exxon Refinery requested a modification to **Permit #1564A2** to support the YELP permit. The permit modification was given **Permit #1564-03**. That request was addressed under the provisions of Subchapter 7, Administrative Rules of Montana

(ARM) 17.8.733(l)(b). Exxon proposed to do the following in conjunction with the YELP permit: (1) send all coker process gases to YELP for treatment; (2) change the manner in which the refinery-wide sulfur-in-fuel emission limitation is calculated (daily to hourly) for all fuel-burning units; (3) change the 1.1 lb/MMBtu sulfur limit to 0.96 lb/MMBtu in order to provide sufficient offsets for the YELP facility; (4) cap the refinery fuel oil burning at 720 barrels per day any time YELP is operating both of its boilers; (5) provide additional verification of SO_2 emission reduction by the addition of recording devices on the Coker CO Boiler (KCOB) fuel oil-firing unit and storage fuel oil system, and by utilizing the present emission calculation/accounting procedures at the refinery.

The projected operational changes in Exxon's general operating permit (#1564A) would reduce SO_2 emissions into the Billings airshed. This reduction takes place as a result of the coker process gas emissions, which include SO_2, CO, coke fines, reduced sulfur compounds and nitrogen oxides (NO_X) being sent to YELP for treatment. This is discussed further in the YELP permit analysis.

In addition, Exxon proposed no fuel oil burning in the KCOB any time YELP is operating two boilers, plus a commitment to adhere to an hourly sulfur-in-fuel limitation on a refinery-wide basis when YELP is operating both of their boilers.

Adherence to an hourly sulfur-in-fuel limitation was changed from 1.1 to 0.96 lb of sulfur in fuel per million Btu fired. This change was equated to a 100-ton/year offset based on actual SO_2 emissions for the past 2 years. In addition, Exxon committed to a daily refinery fuel oil consumption cap of 720 barrels any time YELP is operating two boilers. This condition was insisted upon by the U.S. Environmental Protection Agency (EPA) because of the difficulty in meeting the federal definition of federally enforceable emission limits. Logic suggested that if the YELP facility was to operate as expected and provided the anticipated steam load to Exxon, a larger reduction in SO_2 emissions would actually be realized because of reduced fuel oil firing at the refinery.

It would be critical for both parties, YELP and Exxon, to coordinate their activities closely once operation of YELP had commenced. The Exxon proposal was based on the attached information and more fully explained the 100-ton/year figure and also the rationale for the block hourly 0.96 lb of sulfur-in-fuel figure calculated on a refinery-wide basis.

Exxon had requested that the Montana Department of Environmental Quality (Department) consider revision of their permit when the new 213-foot stack at MSCC was constructed and made federally enforceable. This increase in stack height lessened MSCC's impact and could have decreased the required offset at Exxon for YELP. The Department agreed to provide the opportunity for such a revision. However, before Exxon's sulfur-in-fuel limit could be increased, the new 213-foot stack had to be made federally enforceable through a modification of MSCC's air quality permit. Further, the Department believed the increased stack height may have been necessary to address concerns with the current State Implementation Plan (SIP) and, therefore, may not have been available to reduce the required emission offset at Exxon.

On November 12, 1994, Exxon was issued **Permit #1564-04** to construct and operate an 800-ton/day PMA unit. The PMA unit would allow Exxon to produce polymerized asphalt.

Conventional asphalt base stock is mixed with solid polymer pellets in a wetting/mixing tank, ground with a sheer mill, and returned to the PMA storage tank. The PMA is then loaded out through existing stubs at the west rack. No additional steam demand or fuel consumption was necessary for the PMA project. Volatile Organic Compound (VOC) emissions were the primary pollutants of concern; however, all VOC emissions from equipment and tanks in asphalt service were assumed to be negligible since asphalt has negligible vapor pressure at the working temperature seen in the unit.

This alteration also addressed Exxon's August 9, 1994, modification request to replace the strip recorder of the tank gauging device on the fuel oil storage system with a data transmission system inputting to a data acquisition system (DAS). This modification would allow Exxon to use the computer system to collect and archive the fuel data to meet permit conditions.

On August 25, 1995, Exxon was issued **Permit #1564-05** for a stack extension to the D-4 drum atmospheric vent stack constructed in July 1993. The stack extension raised the height of the D-4 drum atmospheric vent stack from 40.8 meters (134 feet) to 70.1 meters (230 feet). In addition, steam injection capability was added to raise the effective height of the stack to 79.2 meters. The stack extension was designed to eliminate refinery worker exposure impacts during emergencies.

The D-4 atmospheric vent drum was a safety device used to control and manage both routine and abnormal releases from process units. A limited number of safety valves and intermittent blowdowns from the crude, hydrofiner and coker units were vented to this drum. Inside the drum, a continuous flow of water cooled any safety valve releases or blowdowns to condense vapors for subsequent treatment in the wastewater treatment plant. Any vapors not condensed exited through the D-4 drum atmospheric vent stack.

On January 14, 1996, Exxon was issued **Permit #1564-06** to construct the FCC/CO Boiler stack extension from 63.4 to 76.7 meters and the F-2 Crude/Vacuum Heater stack from 63.6 to 65 meters. As part of the 1995 proposed Billings/Laurel SO_2 SIP, Exxon and the Department stipulated that Exxon shall extend the heights of the F-2 Crude/Vacuum Heater and FCC/CO Boiler stacks to at least 65 meters. Exxon was allowed to raise these stacks to above 65 meters, but received a Good Engineering Practices (GEP) credit for modeling purposes of 65 meters. Exxon would be entitled to a greater GEP credit for either stack if a physical demonstration (fluid model or field study) was conducted and justified a taller GEP stack height.

On June 17, 1996, the Department issued **Permit #1564-07** to modify the opacity limitations for the wetting/mixing tank exhaust vent in the PMA unit. The requirements of 40 CFR 60, Standards of Performance for New Stationary Sources (NSPS), Subpart UU – Standards of Performance for Asphalt processing and Asphalt Roofing Manufacture, were reviewed during the initial permit review and it was determined that this subpart was not applicable to the wetting/mixing tank because the tank was used for mixing only and did not store asphalt; therefore, it did not meet the definition of a storage tank. The opacity limit set in the original permit, however, was representative of an asphalt tank that was used for storage of asphalt as defined under NSPS, Subpart UU. The permitted opacity limit did not recognize the fact that mixing asphalt is occurring in the mixing tank. Due to mixing, there may have been a noticeable opacity at the wetting/mixing tank top, even when mixing temperatures were well below 400^{o} F.

A 20% opacity limit was set to reflect the effects of minor mixing in the wetting/mixing tank, which was consistent with ARM 17.8.304 (2). This rule required that no person may cause or authorize emissions to be discharged to an outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

Exxon would still need to maintain the operating temperature of the wetting/mixing tank below the smoking point of asphalt in order to comply with the 20% opacity limit. The wetting/mixing tank only operates intermittently during the summer asphalt season. Any opacity is localized inside the refinery and does not create a public nuisance.

On April 9, 1999, the Department received a request to modify Exxon's Permit #1564-07 to bring the permit closer to the requirements of the June 12, 1998, Stipulation between Exxon, the Department, and the Board of Environmental Review (Board). The changes reduced the reporting and recordkeeping burden for both Exxon and the Department, updated the permit with current rule references, and consolidated all the previously issued permits to Exxon in **Permit #1564-08**.

Exxon also holds a permit for the bulk marketing distribution terminal located adjacent to the refinery. Although the refinery and bulk terminal hold separate preconstruction permits, for any Prevention of Significant Deterioration (PSD) permitting action, the refinery and bulk terminal are considered one facility and must be evaluated as such for any emission increases or decreases.

Permit #1564-08 replaced Permit #1564-07 and all permits identified in Table I.2 of Permit #1564-08.

On July 1, 1997, Exxon applied via Permit Application #1564-08a to construct a sulfur processing facility to be located at the Billings refinery. Exxon was the applicant, with TRC Consultants performing the Best Available Control Technology (BACT)/regulatory analysis and the modeling impact analysis. The Department on July 31, 1997, requested additional permitting information and clarification. Formal responses to the original deficiencies were received on September 4, 1997, and a confidential package, protected under court order, was received on October 2, 1997. Exxon transfers via pipeline, sour fuel gas and acid gas (H_2S) to the MSCC facility located adjacent to the refinery. The proposed sulfur processing facility would have eliminated the need to send the gases off site and would have enabled Exxon to treat the sour fuel gas and acid gas streams and produce sulfur as a marketable product.

On October 7, 1997, the Department was informed that Exxon had signed a multi-year contract with MSCC and the project was on hold. On October 16, 1997, Exxon requested a meeting with the Department to formally withdraw the permit application and request that all materials submitted in support of the application be returned to Exxon. The material was to include all volumes of the application submittals and the package of confidential business information submitted on October 2, 1997. On

October 22, 1997, the Department sent a letter to acknowledge the official withdrawal of Application #1564-08a and to inform Exxon that the materials submitted in support of the application would not be returned to Exxon. The Department's legal staff had confirmed that the public record must be preserved and the materials could not be returned to the applicant.

On August 21, 2000, Exxon submitted a permit application to the Department, with additional submittals on November 13, 2000, and November 22, 2000. The submittals requested the following changes to Permit #1564-08:

1. Addition of one new furnace (F-1201) with a firing capacity of 99 MMBtu/hr or less;

2. Allowance for the modification of furnace F-700 to increase its firing capability from 105.6 MMBtu/hr to 122 MMBtu/hr; and

3. Modification to the method of operation of Tank 26 to reduce volatilization of the stored petroleum product.

4. A name change from Exxon Company U.S.A. to Exxon Mobil Corporation (received January 7, 2000).

5. Clarification of new operating temperature used in Section II.E.1. The description of the operating temperature was changed from "minimum operating temperature" to "operating temperature of the wetting/mixing tank below the smoking point of asphalt."

6. Attachment of the letter dated September 25, 1989, which specifies the monitoring procedures (Appendix A) to be used for the permit (the above letter was previously referenced for monitoring procedures).

The requirements contained in Section II, Parts B and C, concerning an hourly limitation on sulfur in fuel and a daily limitation on fuel oil firing, respectively, apply on a refinery-wide basis to all fuel-burning units at the refinery, consistent with the 1977 Stipulation. **Permit #1564-09** reflected all of the above changes and replaced Permit #1564-08.

Permit #1564-10 was not issued. Two applications were received within the same time period to alter Permit #1564-09 and were not issued in the order in which they were received. To avoid confusion in referencing these permit applications and actions, Permit #1564-10 was removed from use.

On March 3, 2001, the Department issued a permit for the installation and operation of two temporary aero-derivative jet engine electricity generators (Model LM1500), each capable of generating approximately 10 megawatts of power, and an accompanying diesel storage tank. These generators were necessary because of the high cost of electricity. The operation of the generators would not occur beyond 2 years and was not expected to last for an extended period of time, but rather only for the length of time necessary for ExxonMobil to acquire a more economical supply of power. Because these generators would only be used when commercial power was too expensive to obtain, the amount of emissions expected during the actual operation of these generators was minor. In addition, the installation of these generators qualified as a "temporary source" under the PSD permitting program because the permit limited the operation of these generators to a time period of less than 2 years. Therefore, ExxonMobil was not required to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators were considered temporary, the Department required compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 was ensured. In addition, ExxonMobil was responsible for complying with all applicable air quality standards. **Permit #1564-11** replaced Permit #1564-09.

On May 16, 2001, the Department issued a permit for the installation and operation of a temporary aero-derivative jet engine electricity generator (Model LM1500), capable of generating approximately 10 megawatts of power. This generator would be used in addition to the two similar generators permitted in #1564-11 and would be considered a part of the same project with respect to time constraints. This generator and the two generators previously permitted are necessary because of the high cost of electricity. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for ExxonMobil to acquire a more economical supply of power.

As previously mentioned, because the generators will only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of the generators is minor. In addition, the installation of the generators qualifies as a “temporary source” under the PSD permitting program because the permit will limit the operation of the generators to a time period of less than 2 years. Therefore, ExxonMobil will not need to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department requires compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 will be ensured. In addition, ExxonMobil is responsible for complying with all applicable air quality standards. **Permit #1564-12** replaced Permit #1564-11.

On February 13, 2002, the Department received a permit application to address emission increases associated with the modifications that allowed approximately 500 barrels per day more fresh feed to be processed through the Fluid Coker unit (Coker). Other units/processes that were affected by the proposed modifications included the fluidized catalytic cracking unit (FCCU), the motor gasoline (mogas) storage tank throughputs, and the refinery fuel gas system throughput. Included in this permitting action was a limit on refinery-wide fuel oil combustion used to keep the overall SO_2 emissions increase from the project below PSD SO_2 significance levels. In addition, a contemporaneous decrease in VOC emissions on Tank #309 offset the increase in VOC emissions from the project, to keep the project below PSD VOC significance levels.

The project involved the following activities (not all of them requiring permitting, but all included in the application as they relate to the overall project):

1. Replace the existing product coke line with a larger diameter pipe and remove a number of bends and turns to decrease piping pressure drop. Line size increased from 6 inch to 8 inch in diameter and allowed for a product coke capacity of approximately 550 tons per day. This line connects from the Coker unit to the BGI coke silo (capacity related);

2. Upgraded the gearbox of the Coker light ends compressor to facilitate compressing the increased volume of light ends from the higher throughput at the Coker. This compressor (C-311) is located in the refinery Gas Compressor Building near the north end of the FCCU facility (capacity related);

3. Installed new steam aeration nozzles and replaced appropriate sections of the scouring coke line from the Coker burner to the reactor. This allowed improved coke circulation and allowed ExxonMobil to avoid excessive coke buildup at the Coker area (maintenance related);

4. Installed a multi-hole orifice chamber in the Coker Process Gas line that goes to either BGI or the Coker CO Boiler. This device stabilized the back-pressure that the slide valves, located on the top of the Coker burner vessel, have to control. This device allowed smoother transition in unit operations whenever the Coker Process Gas must be diverted away from BGI and back to the Coker CO Boiler (maintenance and capacity related);

5. Modified the cyclone outlet from the Coker reactor to the scrubber section to a newer design, which has a custom designed elbow and larger horn (outlet), decreasing the velocity and pressure drop through the cycle to accommodate an increased vapor rate. The cyclone is located at the top of the Coker reactor outlet and carries reactor hydrocarbon vapors into the scrubber section of the vessel (capacity related);

6. Modified the internals of the D-202 Coker Fractionator Overhead receiver drum to improve liquid/vapor separation. This drum is located at the Coker unit (capacity related);

7. Modified the Coker reactor feed pumps and drivers to increase capacity to match the 500 barrel per day unit increase and higher discharge pressure requirements. The reactor feed pumps take oil from the scrubber and recycle this liquid back to the feed surge drum and supply the reactor feed nozzles. By increasing the speed of the pump impellars, both pressure and increased capacity requirements are satisfied without having to replace the pumps. The bearing housings would be upgraded, if necessary, to safely achieve these higher speeds (capacity related);

8. Modified the reactor feed nozzle system with an improved design. The intent of these changes was to optimize the Coker unit feed nozzle system operation (capacity related); and

9. Included adequate safety facilities to address safety concerns at the higher Coker unit capacity. This may have included replacement of some vessel nozzles and connecting piping to upgrade metallurgy or refractory linings such that higher operating temperatures could be achieved. This may have also included the installation of larger safety valves and associated piping (capacity related).

Permit #1564-13 replaced Permit #1564-12.

On October 22, 2003, the Department received a Montana Air Quality Permit Application from ExxonMobil to modify Permit #1564-13 to meet the EPA 15 parts per million (ppm) sulfur standard for highway diesel fuel. On December 4, 2003, the Department deemed the application complete. Units/processes that were affected by the proposed modifications included the Kerosene Hydrofiner (Hydrofiner No. 3), Diesel Hydrofiner (Hydrofiner No. 1), new facilities to segregate Hydrocracker diesel from Hydrofiner No. 1 diesel, and modifications and additions to facilities to segregate highway and off-road No. 2 diesel fuels. The modifications resulted in an increase in throughput through the FCCU and an increase on motor gas (mogas) production. This permitting action resulted in a limit on refinery-wide fuel oil combustion so that the overall SO_2 emissions increase from the project would stay below the PSD SO_2 significance levels. The permit action took out all references to the temporary generators that were previously permitted and were removed from the facility. The equation for Tank 26 was updated to more accurately account for temperature and pressure in the calculation of VOC emissions for Tank 26. **Permit #1564-14** replaced Permit #1564-13.

On April 9, 2004, the Department received a Montana Air Quality Permit Application from ExxonMobil to modify Permit #1564-14 for changes in how ExxonMobil planned to meet the EPA's 15 ppm sulfur standard for highway diesel fuel. Units/processes affected by the proposed modifications included the addition of a lubricity facility and the addition of minor piping. ExxonMobil no longer planned to segregate Hydrocracker diesel from Hydrofiner No. 1 diesel, or to segregate highway and off-road No. 2 diesel fuels. The current modification resulted in an increase in throughput through the FCCU, an increase in mogas production, an increase at the Hydrogen Unit, and an increase in throughput at the marketing terminal. The permitting action resulted in a limit on refinery-wide fuel oil combustion so that the overall SO_2 and particulate matter (PM) emissions increase from the project would stay below the PSD SO_2 and PM significance levels. **Permit #1564-15** replaced Permit #1564-14.

E. Current Permit Action

On February 9, 2005, the Department of Environmental Quality (Department) received a complete Montana Air Quality Permit Application from ExxonMobil to modify Permit #1564-15. The purpose of the application is to address the replacement of six existing convection section tubes with six new finned convection section tubes in the Steam Reforming Furnace (F-551) located in the Hydrogen Plant. Replacing and finning the upper tube row in the secondary preheat coil of F-551 allows for improved heat absorption from the process stream which in turn results in improved Hydrogen Plant production. The current modifications will directly affect F-551 and, potentially, indirectly increase throughput to the FCCU, Alkylation Unit, Powerformer Unit, and Hydrocracker Unit. Crude oil throughput will not increase as a result of this modification. This permitting action results in lowering the existing limit on refinery-wide fuel oil combustion so that the overall SO_2 and PM emissions increase from the project will be below the PSD SO_2 and PM significance levels. Section II.F.2 of the permit analysis includes a discussion of the netting analysis conducted for the current permit action. **Permit #1564-16** replaces Permit #1564-15.

F. Additional Information

Additional information, such as applicable rules and regulations, BACT/Reasonably Available Control Technology (RACT) determinations, air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

The following are partial quotations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available, upon request, from the Department. Upon request, the Department will provide references for location of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1, General Provisions, including, but not limited to:

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   ExxonMobil shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means which, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

B. ARM 17.8, Subchapter 2, Ambient Air Quality, including, but not limited to:

1. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
2. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
3. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
4. ARM 17.8.213 Ambient Air Quality Standard for Ozone
5. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
6. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility

8. ARM 17.8.222 Ambient Air Quality Standard for Lead
9. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}
10. ARM 17.8.230 Fluoride in Forage

ExxonMobil must maintain compliance with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3, Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. This rule requires an opacity limit of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.324(3) Hydrocarbon Emissions--Petroleum Products. No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule, or is a pressure tank as described in (1) of this rule.

5. ARM 17.8.340 Standard of Performance for New Stationary Sources. This rule incorporates, by reference, 40 CFR 60, Standards of Performance for New Stationary Sources (NSPS). ExxonMobil is considered an NSPS affected facility under 40 CFR 60 and is subject to the requirements of the following subparts.

   40 CFR 60, Subpart J, Standards of Performance for Petroleum Refineries. This subpart applies to facilities that are constructed or modified after June 11, 1973; therefore, new and modified fuel gas combustion devices will be subject to the provisions of Subpart J.

   40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels. This subpart shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984. These requirements shall be as specified in 40 CFR Part 60.110b through 60.117b.

   40 CFR 60, Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries. ExxonMobil will comply with Subpart GGG, as applicable, for the Fluid Coker project, Hydrofiner #1 (HF-1), and Hydrofiner #3 (HF-3).

40 CFR 60, Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems. This rule pertains to facilities that are constructed or modified after May 4, 1987. The affected facilities include an individual drain system, an oil-water separator, and an aggregate facility (drain system included with downstream sewer lines and oil-water separators).

6. ARM 17.8.341 Standards of Performance for Hazardous Air Pollutants. The source shall comply with the standards and provisions of 40 CFR 61, as appropriate.

   40 CFR 61, Subpart FF, National Emission Standards for Benzene Waste Operations. The source shall comply with the standards and provisions of 40 CFR 61, Subpart FF, as appropriate.

7. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR 63, shall comply with the requirements of 40 CFR 63, as appropriate.

   40 CFR 63, Subpart Q, National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers. This regulation applies to the usage of chromium-based water treatment chemicals.

   40 CFR 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries. This regulation applies to petroleum refining process units and to related emission points as specified in this Subpart.

D. ARM 17.8, Subchapter 5, Air Quality Permit Application, Operation, and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. ExxonMobil submitted the appropriate permit application fee for the current permit action.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminant holding an air quality permit (excluding an open-burning permit) issued by the Department; and the annual air quality operation fee is based on the actual or estimated actual amount of air contaminants emitted during the previous calendar year.

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

E. ARM 17.8, Subchapter 7, Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit alteration to construct, alter, or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. ExxonMobil has a PTE greater than 25 tons per year of PM, particulate matter with an aerodynamic diameter 10 microns or less (PM_{10}), NO_X, CO, VOC, and SO_2; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration, or use of a source. ExxonMobil submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. ExxonMobil submitted an affidavit of publication of public notice for the January 26, 2005, issue of the *Billings Gazette*, a newspaper of general circulation in the Town of Billings in Yellowstone County, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving ExxonMobil of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of Intent to Transfer, including the names of the transferor and the transferee, is sent to the Department.

F. ARM 17.8, Subchapter 8, Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. ExxonMobil's existing Billings petroleum refinery (including both the refinery and the bulk terminal) is defined as a "major stationary source" because it is a listed source with the PTE more than 100 tons per year of several pollutants (SO_2, CO, NO_X, and VOCs).

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemption. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this chapter would otherwise allow.

   ExxonMobil's proposed action (#1564-16) is not defined as a "major modification" because after considering all contemporaneous emission increases and decreases and after establishing federally enforceable permit conditions on fuel oil consumption, the potential emissions from this project are below significance levels for all pollutants.

The new annual potential SO_2 emissions associated with the project are approximately 93.2 tons, which would exceed the PSD significance level. ExxonMobil proposed a limit on facility-wide fuel oil combustion resulting in a net emissions increase below the PSD threshold. The actual emissions increase (netting analysis) was evaluated using the 5-year period from the spring of 2000 through the spring of 2005. Taking into consideration all contemporaneous increases and decreases, the net emissions decrease for the project would be 82.9 tons per year, below the PSD significance level of 40 tons per year. The analysis considers 176.1 tons per year in decreases (associated with taking the limit on facility-wide fuel oil combustion).

The new annual potential PM emissions associated with the project are approximately 8.5 tons and added to the ULSD permitting action emissions of 20.5 tons and 0.1 tons from the FCC CO Boiler RFG use increase, which would exceed the PSD significance level. ExxonMobil proposed a limit on facility-wide fuel oil combustion to reduce the net emissions increase to below the PSD threshold. The actual emissions increase was evaluated using the 5-year period from the spring of 2000 through the spring of 2005. Taking into consideration all contemporaneous increases and decreases, the net emissions increase for the project would be 19.6 tons per year, below the PSD significance level of 25 tons per year. The analysis considers 29.1 tons per year of increases and 9.5 tons per year in decreases (associated with taking the limit on facility-wide fuel oil combustion).

In order for a change in emissions to be used in a net emissions analysis, the change has to be creditable and contemporaneous. In order for an increase or decrease to be creditable, it cannot have been relied upon in issuing a PSD permit and an actual increase or decrease in emissions has to occur or have occurred. A creditable decrease also must be federally enforceable. The contemporaneous emissions decreases of 228.5 tons per year of SO_2 comes from permitting actions, #1564-14 in 2004, that included a 52.4 ton per year decrease from the ULSD project. The contemporaneous emissions increase from the Coker of 20.5 tons per year of PM comes from a permitting action, #1564-14 in 2004, and a minor increase of 0.1 tons per year from the increase in RFG burned in the FCC CO Boiler. The contemporaneous emissions decrease of 176.1 tons per year of SO_2 and 9.5 tons per year of PM come from the further reduction in facility wide fuel oil consumption 11.2-kbarrels/year to 3.0 -kbarrels/year made federally enforceable in this permitting action.

The following table illustrates the net emissions increase.

	SO_2 Emissions (tpy)	**VOC Emissions (tpy)**	**CO Emissions (tpy)**	**NO_X Emissions (tpy)**	**PM_{10} Emissions (tpy)**	**PM Emissions (tpy)**
Net Emission Increases Due to Proposed Modifications	93.24	2.14	16.23	38.38	3.97	8.54
Contemporaneous Emissions Increases						20.6
Contemporaneous Emissions Decreases	176.1					9.5
Net Emissions Increase	**(82.86)**	**2.14**	**16.23**	**38.38**	**3.97**	**19.64**
PSD Significance Level	40.0	40.0	100.0	40.0	15.0	25.0

G. ARM 17.8, Subchapter 12, Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:

   a. PTE > 100 tons/year of any pollutant;

   b. PTE > 10 tons/year of any one Hazardous Air Pollutant (HAP), PTE > 25 tons/year of a combination of all HAPs, or a lesser quantity as the Department may establish by rule; or

   c. PTE > 70 tons/year of PM_{10} in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #1564-16 for ExxonMobil, the following conclusions were made:

   a. The facility's PTE is greater than 100 tons/year for several pollutants.

   b. The facility's PTE is greater than 10 tons/year for any one HAP and greater than 25 tons/year of all HAPs.

   c. This source is not located in a serious PM_{10} nonattainment area.

   d. This facility is subject to NSPS requirements.

   e. This facility is subject to current NESHAP standards.

   f. This source is not a Title IV affected source, nor a solid waste combustion unit.

   g. This source is not an EPA designated Title V source.

   Based on these facts, the Department determined that ExxonMobil is a major source of emissions as defined under Title V. ExxonMobil submitted a Title V Operating Permit application on June 12, 1996, and a final Title V permit (OP1564-00) was issued on December 2, 2001.

III. BACT Determination

A BACT determination is required for each new or altered source. ExxonMobil shall install on the source the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. BACT has been evaluated for SO_2 emissions from the FCC CO Boiler and for SO_2, NO_X, and CO emissions from the Process Heater Hydrogen Plant (F-551) in accordance with ARM 17.8.752.

Because estimated VOC and PM_{10} emissions increases for the project are low compared to the existing VOC and PM_{10} emissions, BACT for VOC and PM_{10} is no additional control.

Identify All Control Technologies

Available control options for the emissions in question are listed. Control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and regulated pollutant being evaluated.

A. SO_2

1. FCC CO Boiler and Hydrogen Plant (F-551)

   a. Flue-Gas Scrubbing

      Scrubber is a general term that describes air pollution devices or systems that use absorption, both physical and chemical, to remove pollutants from the process gas stream. Scrubber systems rely on a chemical reaction with a sorbent to remove a wide range of pollutants, including SO_2. Scrubber systems are generally classified as “wet” or “dry.”

      In a wet scrubber, a liquid sorbent is sprayed into the flue gas as an absorber vessel. The gas phase comes into direct contact with a sorbent liquid and is scrubbed into the liquid. The liquid interface for gas absorption includes liquid sheets, wetted walls, bubbles and droplets. In the wet process, a wet slurry waste or by-product is produced. Uptake of the pollutant by the sorbent results in the formation of a wet solid by-product that may require additional treatment. New wet scrubbers routinely achieve SO_2 removal efficiencies of 95 percent with some scrubbers achieving removal efficiencies of 99 percent.

      In a dry scrubber, particles of an alkaline sorbent are injected into a flue gas, producing a dry solid by-product. In dry scrubbers, the flue gas leaving the absorber is not saturated (the major distinction between wet and dry scrubbers).

      Dry scrubbers can be grouped into three categories: spray dryers, circulating spray dryers, and dry injection systems. Spray dryers are designed for SO_2 removal efficiencies of 70-95%. Circulating dry scrubbers can provide removal efficiencies of more than 90%. Dry injection systems are generally applied when lower removal efficiencies are required. Dry injection systems typically have removal efficiencies ranging from 50-70%.

   b. No Add-on Control

2. Alkylation Unit (F-402), Hydorcracker Unit (F-651), and Powerformer Unit (F-700)

   No Add-on Control

   Refinery fuel gas and natural gas are the only fuels combusted in the process heaters and SO_2 emissions from all these units is small.

B. NO_X

1. FCC CO Boiler, Alkylation Unit (F-402), Hydorcracker Unit (F-651), and Powerformer Unit (F-700)

   No Add-on Control

   Because of the small percentage increase in current actual NO_X emissions add-on control would be cost prohibitive.

2. Hydrogen Plant (F-551)

   a. Selective Catalytic Reduction (SCR)

      SCR is a commonly used post-combustion gas treatment technique for reduction of NO and NO_2 in an exhaust stream for relatively large emitters of NO_X. The process reduces NO_X emissions by injecting ammonia into the flue gas. The ammonia acts as the reducing agent in the presence of a catalyst to form water and nitrogen. The ammonia is injected into the flue gas upstream of a catalyst with an active surface of a noble metal, a base metal oxide, or zeolite-based material. The ammonia may be supplied as anhydrous ammonia, which is vaporized and mixed with a pressurized carrier gas in a five percent concentration. A safer alternative, but less common method, is to inject an aqueous ammonia solution. The ratio of ammonia and NO_X can be varied to achieve the desired level of NO_X reduction; however, increasing the ratio to greater than 1 results in increased unreacted ammonia passing through the catalyst and into the atmosphere (ammonia slip).

      The control technology works best for flue gas between 400 and 800 degrees Fahrenheit when a minimum amount of O_2 is present. Use of zeolite catalyst can extend the upper range of this window to a maximum of 1,100 degrees Fahrenheit. The catalyst and catalyst housing tend to be very large and contain a large amount of surface area. The SCR system is usually operated in conjunction with wet injection and/or low NO_X combustors. Data shows that SCR operated alone allows a higher ammonia slip than does an SCR accompanied by either a wet or dry control technology. The control efficiency for an SCR is typically estimated between 60 and 90 percent. Disposal of spent catalyst must be considered. Unlike zeolite and precious metal catalysts, base metal catalysts constitute hazardous waste.

   b. Selective Noncatalytic Reduction (SNCR)

      SNCR involves the noncatalytic decomposition of NO_X in the flue gas to nitrogen and water using a reducing agent (e.g. urea or ammonia). The reactions take place at much higher temperatures than in an SCR, typically between 1,600 and 2,200 degrees Fahrenheit.

   c. Low Temperature Oxidation (LoTOx)

      Oxygen and nitrogen are injected at about 380 degrees Fahrenheit to transform NO and NO_2 into N_2O_5 using an ozone generator and a reactor duct. N_2O_5, which is soluble, dissociates into N_2 and H_2O in a wet scrubber.

Requirements of this system include oxygen and a cooling water supply. Also, the scrubber effluent treatment needs to be provided. The estimated control efficiency of the system is between 80 and 90 percent.

d. Dry Low NO_X (DLN) Combustion (Staged Combustion)

Dry technologies may be identified as DLN, dry low emissions (DLE), or $SoLoNO_X$. These technologies incorporate multiple stage combustors that may include premixing, fuel-rich zones that reduce the amount of O_2 available for NO_X production, fuel-lean zones that control NO_X production through lower combustion temperatures, or some combination of these. A quench zone may also be present to control gas temperature.

e. Wet Controls

Water or steam injection technology has been well demonstrated to suppress NO_X emissions from gas turbines, but not used as common control for process heaters. The injected fluid increases the thermal mass by dilution and thereby reduces peak temperatures in the flame zone.

NO_X reduction efficiency increases as the water-to-fuel ratio increases. For maximum efficiency, the water must be atomized and injected with homogeneous mixing throughout the combustor. This technique reduces thermal NO_X levels, but may actually increase the production of fuel NO_X. Depending on the initial NO_X levels, wet injection may reduce NO_X by 60 percent or more.

f. Innovative Catalytic Systems (SCONOX and XONON)

Innovative catalytic technologies integrate catalytic oxidation and absorption technology. In the SCONOX process, CO and NO are catalytically oxidized to CO_2 and NO_X; the NO_2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. Ammonia is not required. The limited emissions data for this process reflects more HAP emissions. SCONOX technology has recently been applied to combined cycle turbine generation facilities, since steam produced by a heat of recovery steam generator is required in the process.

The XONON system is applicable to diffusion and lean-premix combustors. It utilizes a flameless combustion system where fuel and air react on a catalyst surface, preventing the formation of NO_X while achieving low CO and unburned hydrocarbon emission levels. The overall combustion system consists of the partial combustion of the fuel in the catalyst module followed by completion of combustion downstream of the catalyst. Initial partial combustion produces no NO_X and downstream combustion occurs in a flameless homogeneous reaction that produces almost no NO_X. The system is totally contained within the combustor and is not an add-on control device. This technology has not been fully demonstrated.

g. Process Limitations

The amount of NO_X and other pollutants formed by the process heaters can be reduced proportionately by limiting operating hours. The use of refinery fuel gas or natural gas as the only combustion fuel helps maintain lower NO_X emissions.

h. No Add-on Control.

C. CO

1. FCC CO Boiler, Alkylation Unit (F-402), Hydrocracker Unit (F-651), and Powerformer Unit (F-700)

No Add-on Control

Because of the small percentage increase in current actual CO emissions the cost to control the small percentage increases would be prohibitive.

2. Hydrogen Plant (F-551)

a. Regenerative Thermal Oxidizers (RTO)/Regenerative Catalytic Oxidizers (RCO)

Oxidation systems elevate the air streams to temperatures where hydrocarbons breakdown into CO_2 and H_2O. Thermal oxidizers use dwell time and temperature to complete the reaction while catalytic oxidizers allow the reaction to happen at a lower temperature but the catalyst can become poisoned or masked. Solvent laden air travels through one chamber of ceramic heat absorbing saddles or structured packing, and enters the combustion chamber. After combustion, the warm clean air travels over the second chamber, heating the ceramic packing. At measured time intervals, the process air is switched from one chamber to the next in order to effectively use the heat recovered from the ceramic packing to elevate the process air close to operating temperatures. The estimated control efficiency of the system is at least 95 percent.

b. No Add-on Control.

D. VOC

FCC CO Boiler, Alkylation Unit (F-402), Hydorcracker Unit (F-651), Powerformer Unit (F-700), and Hydrogen Plant (F-551)

Typically, the same pollution control for CO control can be used for VOC control.

E. PM_{10}

FCC CO Boiler, Alkylation Unit (F-402), Hydorcracker Unit (F-651), Powerformer Unit (F-700), and Hydrogen Plant (F-551)

Because of the minor changes in PM_{10} emissions associated with the permitting action no additional control for PM_{10} was proposed.

Eliminate Technically Infeasible Options

The technical feasibility of the control options identified is evaluated with respect to the source-specific factors. A demonstration of technical infeasibility should be clearly documented and shown, based on physical, chemical, and/or engineering principles. If options are eliminated in this step, the analysis should show technical difficulties would preclude the successful use of the control options on the emissions unit under review. Technically infeasible control options may then be eliminated from further consideration.

A. SO_2

FCC CO Boiler and Hydrogen Plant (F-551)

All of the identified SO_2 controls are considered technically feasible.

B. NO_X

Hydrogen Plant (F-551)

LoTOx needs a cooling water supply and water treatment;
Wet control systems are typically used in combustion turbines and not on relatively small process heaters; and
Innovative catalytic systems are technologies mainly used in combustion turbines and not on relatively small process heaters.
Therefore, these control options are eliminated from the analysis.

C. CO

Hydrogen Plant (F-551)

All of the identified CO controls are considered technically feasible.

Rank Remaining Technologies by Control Effectiveness

Available control technology options deemed technically feasible are ranked in order of pollutant removal effectiveness. The control option that results in the highest pollution removal value is considered the top control alternative.

A. SO_2

1. FCC CO Boiler and Hydrogen Plant (F-551) — Control Efficiency

Flue-gas Scrubbing	95%
No Add-on Controls	0%

2. Alkylation Unit (F-402), Hydorcracker Unit (F-651), and Powerformer Unit (F-700)

   No Add-on Control

B. NO_X

1. FCC CO Boiler, Alkylation Unit (F-402), Hydorcracker Unit (F-651), and Powerformer Unit (F-700)

   No Add-on Control

2. Hydrogen Plant (F-551)

SCR	70-90%
DLN Retrofits	80%
SNCR	30-60%
Process Limitations	Varies
No Add-on Controls	0%

C. CO

1. FCC CO Boiler, Alkylation Unit (F-402), Hydorcracker Unit (F-651), and Powerformer Unit (F-700)

   No Add-on Control

2. Hydrogen Plant (F-551)

RCO/RTO	95%
No Add-on Controls	0%

Evaluate Most Effective Controls and Document Results

A. SO_2

FCC CO Boiler and Hydrogen Plant (F-551)

Scrubber economic evaluations were conducted using the methods outlined in *Air Pollution Technology Fact Sheet*, also known as the “Air Pollution Control Technology Fact Sheet” EPA-452/F-03-034 on flue gas desulfurization (FGD). The “Air Pollution Control Technology Fact Sheet” estimates FGD costs on a dollar per MMBtu ($/MMBtu) basis. FGD cost range is $25,000.00 to $150,000.00 per MMBtu.

The heat input of the FCC CO Boiler is 256 MMBtu/hr and the Hydrogen Plant (F-551) has an annual average heat input of 130 MMBtu/hr. The lowest estimated FGD cost of $25,000.00, plus a 30 percent increase for retrofitting, per MMBtu was used. The lowest estimated cost effectiveness for the scrubber application to the FCC CO Boiler and Hydrogen Plant (F-551) are shown below.

Scrubber Cost-Effectiveness			
Emitting Unit	**Tons Removed / Year (tons)**	**Annual Cost ($/year)**	**Cost-Effectiveness ($/ton)**
FCC CO Boiler	77	1,846,876	23,985
F-551	12.4	969,623	78,195

B. NO_X

Hydrogen Plant (F-551)

The method for calculating total annual costs for DLN were conducted based on the methods outlined in EPA 452/B-02-001, *Office of Air Quality Planning and Standards Control Cost Manual*, 6th Edition (OAQPS) September 2000. A manufacturer provided total capital costs for DLN retrofits. The capital cost was annualized over 10 years at 10% interest.

A DLN retrofit for Hydrogen Plant (F-551) is relatively more expensive than a typical retrofit because of the large number of burners (80), ExxonMobil would need to modify the refractory and heater walls to acomidate the DLN burners, ExxonMobil would need to add stainless steel piping due to corrosive H_2S in wet refinery fuel, fuel gas filters would need new foundations for the retrofit, and a filter would need to be installed prior to the retrofit to clean the refinery fuel gas.

General cost effectiveness for NO_X control technologies such as SCR and SNCR were taken from the manual, *Controlling Nitrogen Oxides Under the Clean Air Act* (STAPPA/ALAPCO, July 1994). The cost effectiveness for SCR and SNCR were adjusted from 1994 to 2003 dollars using the producer price index.

Hydrogen Plant (F-551) has an average firing rate of 130 MMBtu/hr of heat input. The SCR and SNCR cost values were interpolated from a 75 MMBtu/hr process heater and a 200 MMBtu/hr process heater since this was the best representation for Hydrogen Plant (F-551). The values in the table do not take into account the change in NO_X emissions and assumes an 80% control of NO_X by the SCR and SNCR. Retrofitting the process for SCR and SNCR, or installing stainless steel piping, and the cost-effectiveness is not calculated into the capital cost of the equipment. If a full cost analysis were performed the cost effectiveness ($/ton) would be much higher. The intent of the data is to present the fact that SCR and/or SNCR is cost-prohibitive even on new process heaters of this size.

Environmental concerns with SCR include spent catalyst disposal. Many of the catalyst formulations are potentially toxic and subject to hazardous waste disposal regulations.

Refinery fuel gas and natural gas are proposed to be the only combustion fuels for Hydrogen Plant (F-551). ExxonMobil does not propose to establish any refinery fuel gas or natural gas consumption limit for the process heater.

NO_X Removal Cost-Effectiveness				
Emitting Unit	**Control Technology**	**Tons Removed / Year (tons)**	**Annual Cost ($/year)**	**Cost-Effectiveness ($/ton)**
F-551	DLN	60.4	973,728	16,121
	SCR	60.4	244,800	4,053
	SNCR	60.4	152,800	2,530

C. CO

Hydrogen Plant (F-551)

The CO BACT analysis was conducted using information from the *Office of Air Quality Planning and Standards Control Cost Manual*, 5th Edition, February 1996 (OAQPS Manual).

The RTO and RCO economic evaluations were conducted using the methods outlined in the OAQPS Manual for fixed-bed catalytic incinerators with 70% energy recovery and regenerative thermal incinerators with 90% energy recovery.

Direct and indirect installation costs were added and direct and indirect annual costs were determined as directed by the OAQPS Manual. Capital costs were annualized over a 10-year period at an interest rate of 10%. Additional fuel costs were conservatively estimated using mean heat capacities of air assumed to be an ideal combustion gas.

RTO and RCO involve potential environmental impacts. RTOs will require the combustion of additional fuel to increase gas temperatures to acceptable levels. This combustion will increase pollutant loading on the environment. Spent catalyst disposal involved with RCO is also an environmental concern. Many of the catalyst formulations are potentially toxic and subject to hazardous waste disposal regulations.

CO Removal Cost-Effectiveness				
Emitting Unit	**Control Technology**	**Tons Removed / Year (tons)**	**Annual Cost ($/year)**	**Cost-Effectiveness ($/ton)**
F-551	RCO	44.4	691,019	15,564
	RTO	44.4	701,401	15,797

Select BACT

A. SO_2

FCC CO Boiler and Hydrogen Plant (F-551)

Flue-gas Scrubbing SO_2 control for the FCC CO Boiler and the Hydrogen Plant (F-551) is cost-prohibitive at $78,195 and $23,985 per ton of SO_2 removed respectively. Due to economic considerations, no additional add-on control is BACT. The BACT determination is consistent with recent BACT determinations for similar sources.

B. NO_X

Hydrogen Plant (F-551)

Control of NO_X emissions for Hydrogen Plant (F-551) using SCR and SNCR is cost-prohibitive. The least expensive option is SNCR at approximately $2,530 per ton of NO_X removed. This is the minimum cost-effectiveness assuming 80% control. The cost of mechanical draft fans, stainless steel piping, retrofits, and associated electrical costs were not included in the SCR and SNCR cost-effectiveness calculations. DLN retrofit is also considered cost-prohibitive at $16,121 per ton of NO_X removed.

NO_X BACT for Hydrogen Plant (F-551) is good combustion practices and combusting only RFG or natural gas. ExxonMobil will comply with this BACT determination by only combusting refinery fuel and/or natural gas in Hydrogen Plant (F-551) and implementing good combustion practices.

C. CO

Hydrogen Plant (F-551)

RTO and RCO application on Hydrogen Plant (F-551) is considered economically infeasible with costs greater than industry norms. RTO and RCO could potentially pose additional adverse energy and environmental impacts. Due to economic, energy, and environmental considerations, BACT for CO is proper design and good combustion practices with no add-on control.

D. VOC

Hydrogen Plant (F-551)

The same pollution control for CO can be used for VOC control. RTO and RCO are common CO and VOC pollution control devices. Since the cost-effectiveness for RTO and RCO control for CO on Hydrogen Plant (F-551) was cost prohibitive and the change in VOC emissions is smaller than the change in CO emissions, RTO and RCO would be cost-prohibitive for VOC control. VOC BACT is proper design and good combustion practices with no add-on control.

E. PM_{10}

FCC CO Boiler, Alkylation Unit (F-402), Hydorcracker Unit (F-651), Powerformer Unit (F-700), and Hydrogen Plant (F-551)

This permitting action created a relatively small change in emissions or a small percent change in actual emissions for these sources. Even though Hydrogen Plant (F-551) has a relatively large change in actual emissions, the cost to control approximately 1.1 tons per year would be prohibitive. With only an approximate 0.2 tons per year increase in PM emissions for the Hydorcracker Unit (F-651) and Powerformer Unit (F-700), the cost to control this relatively small change in PM emissions would be prohibitive. The FCC CO Boiler has the largest increase in PM emissions, but the 2% increase in actual emissions is relatively small; therefore, the cost to control this relatively small percentage change would be prohibitive. BACT for these units is no add-on control devices and good combustion practices.

IV. Emission Inventory

Potential Hydrogen Plant (F-551) Emissions								
Process Unit	**Source**	**SO_2**	**PM**	**PM_{10}**	**CO**	**NO_X**	**VOC**
FCCU	CO Boiler	80.7	7.0	2.5	0.8	5.6	0.1
Hydrogen Plant	F-551	13.1	4.6	4.6	46.7	75.6	5.2
Alkylation Unit	F-402				0.2	0.4	
Hydrocracker Unit	F-651		0.2	0.2	2.2	3.9	0.2
Powerformer Unit	F-700		0.2	0.2	2.2	10.2	0.2
Storage Tanks	Tanks						0.1
Marketing Terminal	Loading						0.2
Total		**93.8**	**12.0**	**7.5**	**52.1**	**95.7**	**6.0**

FCCU: Fresh feed increase to FCCU of 374 barrels/day

SO_2

SO_2 Emission Factor: 1,182.3 lb SO_2/kbarrel (based on 02 and 03 used for actual emissions increase evaluation)

SO_2 Increase: 374 barrels/day * 1,182.3 lb SO_2/kbarrel * 365 day/yr * 0.0005 ton/lb *0.001 kbarrel/barrel = 80.7 ton/yr

PM

PM Emission Factor: 103.1 lb PM/kbarrel (Permit #1564-13)

PM Increase: 374 barrels/day * 103.1 lb PM/kbarrel * 365 day/yr * 0.0005 ton/lb *0.001 kbarrel/barrel = 7.0 ton/yr

PM_{10}

PM_{10} Emission Factor: 36.1 lb PM_{10}/kbarrel (Permit #1564-13)

PM_{10} Increase: 374 barrels/day * 36.1 lb PM_{10}/kbarrel * 365 day/yr * 0.0005 ton/lb *0.001 kbarrel/barrel = 2.5 ton/yr

CO

CO Emission Factor: 11.6 lb CO/kbarrel (based on 02 and 03 used for actual emissions increase evaluation)

CO Increase: 374 barrels/day * 11.6 lb CO/kbarrel * 365 days/yr * 0.0005 ton/lb *0.001 kbarrel/barrel = 0.8 ton/yr

NO_X

NO_X Emission Factor: 82.4 lb NO_X/kbarrel (based on 02 and 03 used for actual emissions increase evaluation)

NO_X Increase: 374 barrels/day * 82.4 lb NO_X/kbarrel * 365 day/yr * 0.0005 ton/lb *0.001 kbarrel/barrel = 5.6 ton/yr

VOC

VOC Emission Factor: 0.95 lb VOC/kbarrel (based on 02 and 03 used for actual emissions increase evaluation)

VOC Increase: 374 barrels/day * 0.95 lb VOC/kbarrel * 365 day/yr * 0.0005 ton/lb *0.001 kbarrel/barrel = 0.1 ton/yr

Hydrogen Plant F-551

SO_2

SO_2 Emission Factor: 0.023 lb SO_2/MMBtu (based on predicted change)

SO_2 Increase: 130 MMBtu/hr * (0.023 lb/MMBtu) * 0.0005 ton/lb * 8760 hr/yr = 13.1 ton/yr

PM

PM Emission Factor: 9.34 lb PM_{10}/MMCF fuel gas (based on predicted change)

PM Increase: 130 MMBtu/hr * (9.34 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 4.6 ton/yr

PM_{10}

PM_{10} Emission Factor: 9.34 lb PM_{10}/MMCF fuel gas (based on predicted change)

PM_{10} Increase: 130 MMBtu/hr * (9.34 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 4.6 ton/yr

CO

CO Emission Factor: 95.71 lb CO/MMCF fuel gas (based on predicted change)

CO Increase: 130 MMBtu/hr * (95.71 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 46.7 ton/yr

NO_X

NO_X Emission Factor: 154.87 lb NO_X/MMCF fuel gas (based on predicted change)

NO_X Increase: 130 MMBtu/hr * (154.87 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 75.6 ton/yr

VOC

VOC Emission Factor: 10.7 lb VOC/MMCF fuel gas (based on predicted change)

VOC Increase: 130 MMBtu/hr * (10.7 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 5.2 ton/yr

Alkylation Unit F-402

SO_2

SO_2 Emission Factor: 1.64 lb SO_2/MMCF fuel gas (based on predicted change)

SO_2 Increase: 0.54 MMBtu/hr * (1.64 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.0 ton/yr

PM

PM Emission Factor: 9.34 lb PM_{10}/MMCF fuel gas (based on predicted change)

PM Increase: 0.54 MMBtu/hr * (9.34 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.0 ton/yr

PM_{10}

PM_{10} Emission Factor: 9.34 lb PM_{10}/MMCF fuel gas (based on predicted change)

PM_{10} Increase: 0.54 MMBtu/hr * (9.34 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.0 ton/yr

CO

CO Emission Factor: 95.71 lb CO/MMCF fuel gas (based on predicted change)

CO Increase: 0.54 MMBtu/hr * (95.71 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.2 ton/yr

NO_X

NO_X Emission Factor: 171.81 lb NO_X/MMCF fuel gas (based on predicted change)

NO_X Increase: 0.54 MMBtu/hr * (171.81 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.4 ton/yr

VOC

VOC Emission Factor: 10.67 lb VOC/MMCF fuel gas (based on predicted change)

VOC Increase: 0.54 MMBtu/hr * (10.67 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.0 ton/yr

Hydrocracker Unit F-651

SO_2

SO_2 Emission Factor: 1.64 lb SO_2/MMCF fuel gas (based on predicted change)

SO_2 Increase: 6.0 MMBtu/hr * (1.64 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.0 ton/yr

PM

PM Emission Factor: 9.34 lb PM_{10}/MMCF fuel gas (based on predicted change)

PM Increase: 6.0 MMBtu/hr * (9.34 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.2 ton/yr

PM_{10}

PM_{10} Emission Factor: 9.34 lb PM_{10}/MMCF fuel gas (based on predicted change)

PM_{10} Increase: 6.0 MMBtu/hr * (9.34 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.2 ton/yr

CO

CO Emission Factor: 95.71 lb CO/MMCF fuel gas (based on predicted change)

CO Increase: 6.0 MMBtu/hr * (95.71 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 2.2 ton/yr

NO_X

NO_X Emission Factor: 171.81 lb NO_X/MMCF fuel gas (based on predicted change)

NO_X Increase: 6.0 MMBtu/hr * (171.81 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 3.9 ton/yr

VOC

VOC Emission Factor: 10.67 lb VOC/MMCF fuel gas (based on predicted change)
VOC Increase: 6.0 MMBtu/hr * (10.67 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.2 ton/yr

Powerformer Unit F-700

SO_2

SO_2 Emission Factor: 1.64 lb SO_2/MMCF fuel gas (based on predicted change)
SO_2 Increase: 6.08 MMBtu/hr * (1.64 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.0 ton/yr

PM

PM Emission Factor: 9.34 lb PM_{10}/MMCF fuel gas (based on predicted change)
PM Increase: 6.08 MMBtu/hr * (9.34 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.2 ton/yr

PM_{10}

PM_{10} Emission Factor: 9.34 lb PM_{10}/MMCF fuel gas (based on predicted change)
PM_{10} Increase: 6.08 MMBtu/hr * (9.34 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.2 ton/yr

CO

CO Emission Factor: 95.71 lb CO/MMCF fuel gas (based on predicted change)
CO Increase: 6.08 MMBtu/hr * (95.71 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 2.2 ton/yr

NO_X

NO_X Emission Factor: 444.62 lb NO_X/MMCF fuel gas (based on predicted change)
NO_X Increase: 6.08 MMBtu/hr * (444.62 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 10.2 ton/yr

VOC

VOC Emission Factor: 10.67 lb VOC/MMCF fuel gas (based on predicted change)
VOC Increase: 6.08 MMBtu/hr * (10.67 lb/MMCF / 1167 MMBtu/MMCF) * 0.0005 ton/lb * 8760 hr/yr = 0.2 ton/yr

Storage Tanks (Increase in Throughput)

VOC

VOC Increase: 1,468 barrel/day increase in throughput = 0.1 ton/yr

Marketing Terminal (Gasoline Loading)

VOC

VOC Emission Factor 6.3 lb VOC/kbbl
VOC Increase: 6.3 lb/kbbl * 0.15 kbbl/day * 365 day/yr * 0.0005 ton/lb = 0.2 ton/yr

V. Air Quality Impacts

Bison Engineering, Inc., on behalf of ExxonMobil submitted a modeling analysis in which the proposed emission increases of NO_X, CO, SO_2, and PM_{10} were modeled and compared against the PSD modeling significance threshold to demonstrate the minimal impact the proposed project would have on ambient air quality.

The EPA approved Industrial Source Complex (ISC3) model and five years of meteorological data (1984, 1986 through 1989) were utilized for the air quality model. The surface data was collected at the Billings International Airport National Weather Station, and the upper air data was collected at the Great Falls International Airport National Weather Station. The receptor grid used in this analysis was an abbreviated version of the receptor grid used in the SIP modeling. The receptor grid consisted of 1931 receptors. The coarse grid receptors are spaced 1,000 meters apart and the fine grid is spaced 100 meters apart.

The modeled sources, source parameters, and emission rates included in the model are identified in Table 1.

Table 1. Modeling Sources and Source Parameters

Source ID	UTM Location			Stack Parameters				Pollutants			
	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Stack Height (ft)	Temp (K)	Exit Velocity (ft/s)	Stack Diameter (ft)	NO_X (lb/hr)	CO (lb/hr)	PM (lb/hr)	SO_2 (lb/hr)
F-551	699480	5076320	3090	195.0	588.7	38.4	5.8	23.35	14.43	1.41	4.05
FCCU	699395	5076350	3091	251.3	583.0	39.5	9.7	1.28	0.18	0.56	-30.87
F-402	699460	5076530	3090	100.0	533.2	18.7	4.0	0.08	0.04	0.00	0.00
F-651	699470	5076330	3090	138.0	560.9	27.6	3.7	0.88	0.49	0.05	0.00
F-700	699560	5076460	3090	208.0	505.4	39.4	9.0	2.32	0.50	0.05	0.01

The modeled concentration was then compared against the "significant" levels for all pollutant emissions as shown in Table 2.

Table 2. Modeling Results

Pollutant	Avg. Period	Modeled Conc. ($\mu g/m^3$)	Significance Conc. ($\mu g/m^3$)	% of Significance
NO_2	Annual	0.54	1	54
CO	1-hr	12.06	2000	0.60
	8-hr	4.85	500	0.97
PM_{10}	24-hr	0.35	5	7
	Annual	0.04	1	4
SO_2	3-hr	1.28	25	5.12
	24-hr	0.21	5	4.2
	Annual	0.003	1	0.3

The results of the analysis show that all the modeled pollution impacts from the proposed project at the refinery are less than the PSD modeling Significance levels. Based on this demonstration, no further modeling is necessary and it is presumed that ExxonMobil will not violate any ambient standard.

VI. Taking or Damaging Implication Analysis

As required by 2-10-101 through 105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

VII. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

DEPARTMENT OF ENVIRONMENTAL QUALITY
Permitting and Compliance Division
Air Resources Management Bureau
1520 East Sixth Avenue
P.O. Box 200901, Helena, Montana 59620-0901
(406) 444-3490

FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued For: Exxon Mobil Corporation
700 Exxon Road
P.O. Box 1163
Billings, MT 59103

Permit Number: #1564-16

Preliminary Determination Issued: February 18, 2005
Department Decision Issued: March 8, 2005
Final Permit Issued: March 24, 2005

1. Legal Description of Site: S½ of Section 24 and N½ of Section 25, Township 1 North, Range 26 East, Yellowstone County, Montana.

2. Description of Project: On February 9, 2005, the Department received a complete Montana Air Quality Permit Application from ExxonMobil to modify Permit #1564-15. The purpose of the application is to address the replacement of six existing convection section tubes with six new finned convection section tubes in the Steam Reforming Furnace (F-551) located in the Hydrogen Plant. Replacing and finning the upper tube row in the secondary preheat coil of F-551 allows for improved heat absorption from the process stream which in turn results in improved Hydrogen Plant production. The current modifications will directly affect F-551 and, potentially, indirectly increase throughput to the FCCU, Alkylation Unit, Powerformer Unit, and Hydrocracker Unit. Crude oil throughput will not increase as a result of this modification. This permitting action results in lowering the existing limit on refinery-wide fuel oil combustion so that the overall SO_2 and PM emissions increase from the project will be below the PSD SO_2 and PM significance levels. Section II.F.2 of the permit analysis includes a discussion of the netting analysis conducted for the current permit action.

3. Objectives of Project: Replacing and finning the upper tube row in the secondary preheat coil of F-551 allows for improved heat absorption from the process stream which in turn results in improved Hydrogen Plant production

4. Alternatives Considered: In addition to the proposed action, the Department also considered the "no-action" alternative. The no-action alternative would deny issuance of the Montana Air Quality permit to ExxonMobil. However, the Department does not consider the "no-action" alternative to be appropriate because ExxonMobil demonstrated compliance with all applicable rules and regulations as required for permit issuance. Therefore, the "no-action" alternative was eliminated from further consideration.

5. A Listing of Mitigation, Stipulations, and Other Controls: A list of enforceable conditions including a BACT analysis would be contained in Permit #1564-16.

6. Regulatory Effects on Private Property: The Department considered alternatives to the conditions imposed in this permit as part of permit development. The Department determined that the permit conditions would be reasonably necessary to ensure compliance with applicable requirements and to demonstrate compliance with those requirements and would not unduly restrict private property rights.

7. The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.

		Major	**Moderate**	**Minor**	**None**	**Unknown**	**Comments Included**
A	Terrestrial and Aquatic Life and Habitats			X			Yes
B	Water Quality, Quantity, and Distribution			X			Yes
C	Geology and Soil Quality, Stability, and Moisture			X			Yes
D	Vegetation Cover, Quantity, and Quality			X			Yes
E	Aesthetics			X			Yes
F	Air Quality			X			Yes
G	Unique Endangered, Fragile, or Limited Environmental Resources			X			Yes
H	Demands on Environmental Resource of Water, Air and Energy			X			Yes
I	Historical and Archaeological Sites				X		Yes
J	Cumulative and Secondary Impacts			X			yes

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats

This permitting action would have a minor effect on terrestrial and aquatic life and habitats, as the proposed project would affect an existing, industrial property that has already been disturbed. Impacts to terrestrial life and habitats may occur as a result of the increased air emissions (SO_2, NO_X, CO, VOC, PM_{10}, and PM). Habitat impacts could result in a change of diversity or abundance of terrestrial or aquatic life. However, this area does not appear to contain any critical or unique wildlife habitat or aquatic life and the project would occur in an already disturbed area.

B. Water Quality, Quantity, and Distribution

Minor, if any, impacts would be expected on water quality, quantity, and distribution from the proposed project because of the relatively small size of the project. While the facility would emit air pollutants, and corresponding deposition of pollutants would occur, as described in Section 7.F. of this EA, the Department determined that, due to dispersion characteristics of pollutants and the atmosphere and conditions that would be placed in Permit #1564-16, any impacts from deposition of pollutants on water quality, quantity, and distribution would be minor.

C. Geology and Soil Quality, Stability, and Moisture

Minor impacts would occur on the geology and soil quality, stability, and moisture from the proposed project because minor construction would be required to complete the project. Any impacts to the geology and soil quality, stability, and moisture from facility construction would be minor because the project would occur at an existing industrial site and on existing equipment.

Further, while deposition of pollutants would occur, as described in Section 7.F of this EA, the Department determined that deposition of pollutants in the areas surrounding the site would be minor due to dispersion characteristics of pollutants and the atmosphere and conditions that would be placed in Permit #1564-16. Overall, any impacts to the geology and soil quality, stability, and moisture would be minor.

D. Vegetation Cover, Quantity, and Quality

This permitting action would have a minor effect on vegetation cover, quantity, and quality. The proposed project would affect an existing, industrial property that has already been disturbed. No additional vegetation on the site would be disturbed for the project. The increase in actual levels of NO_X, CO, VOC, PM_{10}, and PM from historical emission levels might have a minor effect on the surrounding vegetation, however the air quality permit associated with this project contains limitations (facility-wide fuel oil combustion limit and associated New Source Performance Standards) to minimize the effect of the emissions on the surrounding environment. Overall, any impacts to vegetation cover, quantity, and quality would be minor.

E. Aesthetics

The proposed modification to the facility would be constructed in the area that has previously been disturbed and already has noise associated with its operation. The construction involved in the project would be limited to rebuilding of current processes. No new buildings or noise sources would be created, only the process utilization would change. Therefore, only minor impacts to aesthetics would be anticipated.

F. Air Quality

There would be air quality impacts resulting from the proposed project. The net emissions increases associated with the project are shown in the table below.

	PM	**PM_{10}**	**CO**	**NO_X**	**VOC**	**SO_2**
Potential Emissions Increases (tons/year)	19.60	3.97	16.23	38.38	2.14	(82.86)

A refinery-wide limit on fuel oil combustion in this permitting action would reduce the overall potential SO_2 emissions increase. Air quality modeling was conducted for the proposed project as part of the ExxonMobil air quality permit application. The modeling demonstrates that the facility would comply with the Montana and National Ambient Air Quality Standards (MAAQS/NAAQS).

ExxonMobil would be required to maintain compliance with the Billings/Laurel SO_2 State Implementation Plan (SIP), current permit conditions, and state and federal ambient air quality standards. The effect on air quality would be minor.

While deposition of pollutants would occur as a result of operating the facility, the Department determined that any air quality impacts from deposition of pollutants would be minor due to dispersion characteristics of pollutants, the atmosphere (wind speed, wind direction, ambient temperature, etc.), and conditions that would be placed in Permit #1564-16.

G. Unique Endangered, Fragile, or Limited Environmental Resources

According to the Montana Natural Heritage program, there are four animal species of concern in the general vicinity of the refinery. They include the Milk Snake (*Lampropeltis triangulum*), the Peregrine Falcon (*Falco Peregrinus*), the Western Hognose Snake (*Heterodon Nasicus*), and the Spiny Softshell (*Trionyx Spiniferus*). This permitting action may result in minor impacts to terrestrial and aquatic life and/or their habitat; therefore, it is possible that unique, rare, threatened, or endangered species may experience minor impacts. However, the project would occur at a previously disturbed industrial site, within allowable levels of emissions. Therefore, any impacts to unique endangered, fragile, or limited environmental resources would be minor.

H. Demands on Environmental Resources of Water, Air, and Energy

As described in Section 7.B of this EA, this permitting action would have little to no effect on the environmental resource of water as there would be no discharges to groundwater or surface water associated with this permitting action.

As described in Section 7.F of this EA, the impact on the air resource in the area of the facility would be minor because the air emissions from the proposed project are low and the facility would be required to maintain compliance with other limitations affecting the overall emissions from the facility and the project would not increase current water use at the facility.

A minor impact to the energy resource would be expected, due to a minor increase in fresh feed to the FCCU.

Actual levels of pollutant emissions may increase as a result of this project; however, this action would not include an increase in allowable levels. Previous modeling efforts, using allowable levels, showed compliance with NAAQS and MAAQS. This project would result in a minor effect on the air resource.

I. Historical and Archaeological Sites

In an effort to identify any historical and archaeological sites near the proposed project area, the Department contacted the Montana Historical Society, State Historic Preservation Office (SHPO). According to SHPO records, there have not been any previously recorded historic or archaeological sites within the proposed area. The project would occur within the boundaries of a previously disturbed industrial site. A historic agricultural site 24YL272, dating 1890-1899, is adjacent to the ExxonMobil facility, however, construction associated with the project would be limited to modification of current process components. A cultural resource inventory was conducted in 1985 for the area in question. No additional impacts to the site would be expected to occur.

J. Cumulative and Secondary Impacts

Minor cumulative and secondary impacts would be expected to result from this project with the increase in fresh feed at the FCCU and an increase in mogas production. Yellowstone Energy Limited Partnership and Montana Sulphur and Chemical Company's utilization of the additional product from ExxonMobil could result in an incremental increase in emissions from those facilities. However, those facilities would have their own permit limitations that must be complied with. Therefore, the cumulative and secondary impacts from this project would be minor.

8. The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.

		Major	**Moderate**	**Minor**	**None**	**Unknown**	**Comments Included**
A	Social Structures and Mores				X		Yes
B	Cultural Uniqueness and Diversity				X		Yes
C	Local and State Tax Base and Tax Revenue			X			Yes
D	Agricultural or Industrial Production			X			Yes
E	Human Health			X			Yes
F	Access to and Quality of Recreational and Wilderness Activities				X		Yes
G	Quantity and Distribution of Employment				X		Yes
H	Distribution of Population				X		Yes
I	Demands for Government Services			X			Yes
J	Industrial and Commercial Activity				X		Yes
K	Locally Adopted Environmental Plans and Goals				X		Yes
L	Cumulative and Secondary Impacts			X			yes

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS: The following comments have been prepared by the Department.

A. Social Structures and Mores

The proposed facility would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area because the project would be constructed at a previously disturbed industrial site. The proposed project would not change the nature of the site.

B. Cultural Uniqueness and Diversity

The proposed project would not cause a change in the cultural uniqueness and diversity of the area because the land is currently used as a petroleum refinery; therefore, the land use would not be changing. The use of the surrounding area would not change as a result of this project.

C. Local and State Tax Base and Tax Revenue

This project would have a minor effect on the local and state tax base and tax revenue because this change in process utilization associated with the Ultra-Low Sulfur Diesel project is intended to enable ExxonMobil to continue competitive operation of their facility. Therefore, property tax revenue from the facility might increase slightly. However, no new employees would be added as a result of this project.

D. Agricultural or Industrial Production

The proposed project would not result in a reduction of available acreage or productivity of any agricultural land; therefore, agricultural production would not be affected. Industrial production would change slightly because the asphalt production would be reduced to produce other, higher value products.

E. Human Health

As described in Section 7.F of this EA, the impacts from this facility on human health would be minor because the emissions from the facility would increase, but not significantly from prior levels. The air quality permit for this facility would incorporate conditions to ensure that the facility would be operated in compliance with all applicable rules and standards. These rules and standards are designed to be protective of human health.

F. Access to and Quality of Recreational and Wilderness Activities

The proposed action would not alter any existing access to or quality of any recreational or wilderness area activities. This project would not have an impact on recreational or wilderness activities because the site is far removed from recreational and wilderness areas or access routes. Furthermore, the facility is contained on private property and would continue to be contained within private property boundaries.

G. Quantity and Distribution of Employment

The proposed project would not result in any impacts to the quantity or distribution of employment at the facility or surrounding community. No employees would be hired at the facility as a result of the project.

H. Distribution of Population

The proposed project does not involve any significant physical or operational change that would affect the location, distribution, density, or growth rate of the human population.

I. Demands for Government Services

The demands on government services would experience a minor impact. The primary demand on government services would be the acquisition of the appropriate permits by the facility (including local building permits, as necessary, and a state air quality permit) and compliance verification with those permits.

J. Industrial and Commercial Activity

The level of industrial and commercial activity would not change because the fresh feed would be redirected from the asphalting process to the Coker, staying within the refinery.

K. Locally Adopted Environmental Plans and Goals

The Department is unaware of any locally adopted environmental plans and goals that would be affected by the proposed change to the facility. The conditions associated with the Billings/Laurel SO_2 SIP would apply regardless of the status of the project.

L. Cumulative and Secondary Impacts

Overall, any cumulative and secondary impacts from this project on the social and economic aspects of the human environment would be minor because only the property tax base could possibly increase as a result of this project. The project is associated with an existing facility and would not change the culture or character of the area.

Recommendation: An EIS is not required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: The impacts resulting from this project would not be significant in that the project would be limited to rebuilding of current processes. The overall emissions increase would be minor and the permitting action contains a limit to reduce SO_2 emissions from the facility.

Other groups or agencies contacted or which may have overlapping jurisdiction: None.

Individuals or groups contributing to this EA: Department of Environmental Quality – Air Resources Management Bureau, Montana Historical Society – State Historic Preservation Office, Natural Resource Information System – Montana Natural Heritage Program

EA prepared by: Chris Ames
Date: February 16, 2005

APPENDIX A